FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

D.T.E. 02- __

DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

PERFORMANCE BASED REGULATION PLANS
FOR THE GAS AND ELECTRIC DIVISIONS

April 16, 2002

Massachusetts Department of Telecommunications and Energy

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I. BACKGROUND AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead its Regulation & Litigation Support Practice. I have been employed by NCI since January 1997.

Q. Please describe in more detail the business activities of NCI.

A. NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to information technology, process/operations management, business strategy development, and marketing and sales designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American energy industry, including utility costing and pricing, energy commodity and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at electric and gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous electric and gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 27 years of experience in the utility industry, the last 24 years of which have been in the field of utility management and economic consulting. Specializing in the energy industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, energy commodity planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and several state and provincial regulatory commissions and have spoken widely on issues and activities dealing with the pricing and marketing of gas and electric utility services.

In the area of Performance Based Regulation ("PBR")[1], I have actively participated in projects that address the assessment, development, and implementation of PBR concepts for both gas and electric utilities. Besides assisting in the development of the strategic and computational aspects of the proposals, I have provided ongoing support to our clients to ensure stakeholder acceptance and successful operation of the chosen PBR mechanism. Finally, I have worked with utility senior management to develop performance-based

[1] PBR is sometimes referred to in the industry literature as "Performance-Based Ratemaking" or "Incentive Regulation."

measures for use in benchmarking, against surrounding utilities and best performers, the company's effectiveness in providing reliable service to its customers.

Further background information summarizing my education, presentation of expert testimony, and other industry-related activities is included in Appendix A to my direct testimony.

Q. Have you previously testified before the Department of Telecommunications and Energy (the "Department")?

A. Yes, I have. I previously testified before the Department[2] on behalf of Essex County Gas Company, a subsidiary of Eastern Enterprises, on the subject of gas rate design issues.

II. PURPOSE AND CONCLUSIONS

Q. For what purpose has Fitchburg Gas and Electric Light Company ("FG&E") retained NCI?

A. NCI was retained by FG&E as a consultant in the area of utility rate design and related regulatory matters for its gas and electric operations. Specifically, NCI has provided ongoing assistance to FG&E in the area of PBR, including working closely with its staff to assess the application of PBR concepts to the utility operations of FG&E and to develop

[2] At that time, the Department was known as the Massachusetts Department of Public Utilities.

PBR plans that are based on sound regulatory and economic policy, widely accepted ratemaking principles, and are reflective of the Department's evolving preferences in the PBR area.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to discuss and support the conceptual underpinnings of FG&E's Gas and Electric PBR Plans, and to present and explain the specific components and related mechanisms of FG&E's PBR proposals. FG&E witness Dr. Todd M. Bohan will introduce its Gas and Electric PBR Plans and will provide an overview of its Gas and Electric PBR Filings.

Q. Please summarize your conclusions regarding the proposed PBR Plans of FG&E.

A. Based on my review of the FG&E's operational and regulatory situation, and the Department's clear PBR mandate for gas and electric distribution utilities operating in Massachusetts, I conclude that PBR concepts also should be applied to the gas and electric operations of FG&E to establish its future regulatory framework and ratemaking approach.

In view of the Department's preferences in the PBR area, I conclude that the structural components of FG&E's PBR Plans are consistent with, and fully responsive to, these preferences and are compatible with the current operational configuration and overall management objectives of FG&E.

Finally, based on NCI's active involvement in their design and implementation, I expect that FG&E's PBR Plans will produce tangible benefits for both FG&E and its customers over the coming years by providing FG&E with strong incentives to continue to provide safe and reliable service, while improving operating efficiencies, limiting increases in average customer rates to less than the rate of inflation, ensuring that FG&E provides quality customer service (and requiring customer refunds if service does not meet defined standards), and reducing regulatory and administrative costs.

III. SUMMARY OF FG&E'S PBR PLANS

Q. Please provide a brief summary of the Company's PBR Plans.

A. The PBR Plans submitted for the Gas and Electric Divisions of FG&E are intended to fully comply with Massachusetts statutes and the Department rules and regulations requiring local gas distribution utilities and electric utilities to establish performance-based rates.

Each PBR Plan is comprised of three major components: initial PBR cast-off rates, a price cap mechanism, and a service quality plan. The initial PBR cast-off rates will be established as a result of FG&E's general base rate cases that will be filed on May 17, 2002. The initial PBR cast-off rates establish the appropriate starting point for initiation of FG&E's PBR Plans. The price cap mechanism ("price cap") allows FG&E to adjust its gas and electric distribution base rates and gas production base rates[3] (collectively referred to as "base rates") annually by a factor that reflects price inflation, reduced by an enhanced productivity offset, and adjusted for an exogenous factor and a service quality revenue penalty factor where appropriate. The Service Quality Plan ("SQP") provides a revenue penalty of up to 2 percent of FG&E's base transmission and distribution revenues if FG&E fails to maintain specified levels of safety, reliability and customer service quality as defined in FG&E's approved SQPs. Each PBR Plan has a 10-year term, with an interim 5-year review provision, and becomes effective on January 1, 2003.

Q. Why is FG&E filing PBR mechanisms at this time?

A. FG&E is filing PBR mechanisms at this time to comply with the Department's directives and to have available for implementation an alternative ratemaking framework when its current gas and electric rates are adjusted in its upcoming general rate cases. FG&E will file rate cases for both its gas and electric divisions requesting rate changes on May 17, 2002. With these rate filings, and the expected adjustments to its base rates, FG&E believes it must now implement a PBR mechanism for both its gas and electric operations that will be more consistent with, and supportive of, the business objectives and operational initiatives of

[3] Distribution base rates are defined as the distribution rate components of FG&E's Tariff for Gas Service and Tariff for Electric Service, consisting of the customer, volumetric, and demand charges. Gas production base rates are defined as supply-related components consisting of the Liquified Propane and Liquified Natural Gas ("LPLNG"), Distribution Acquisition and FERC Proceedings ("DAFP"), and Production and Related Overhead ("PRO") rate factors included in FG&E's Cost of Gas Adjustment Clause.

FG&E's management team in the coming years.

Furthermore, FG&E's PBR Plans are fully responsive to the Department's past preferences and more recent directives regarding the filing of PBR plans by Massachusetts gas and electric distribution companies. As summarized in its Order in D.T.E. 99-84[4], the Department stated that in the past, it has encouraged[5] and expected[6] gas and electric distribution utilities to file PBR plans. With Service Quality guidelines now established by the Department, it directed each gas and electric distribution company that files a petition under G.L. c. 164 for a general rate increase to include a PBR plan[7].

Finally, introducing PBR plans at this time provide a necessary vehicle for implementing FG&E's SQPs. The SQPs were filed in compliance with the Department's June 29, 2001 Order in Docket No. D.T.E. 99-84. The Department subsequently approved the Electric Division's SQP. The Gas Division's SQP is pending Department approval. Dr. Bohan addresses in more detail in his direct testimony this aspect of FG&E's filings.

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4 D.T.E. 99-84 at 42.

5 Electric Industry Restructuring: A Model Plan, D.T.E. 96-100 at 115-116 (1996); Incentive Ratemaking, D.P.U. 94-158, at 65-66 (1995).

6 The Department expected a PBR proposal to be a part of each electric company's next base rate case. Electric Industry Restructuring, D.P.U. 96-100 at 116.

7 D.T.E. 99-84 at 42.

Q. Why must initiation of FG&E's PBR Plans await the conclusion of its upcoming general rate cases?

A. It is important that the starting point for any PBR plan be based on rates that reflect a reasonable and current representation of the utility's cost of providing service, on both an overall and class specific basis. Without such a starting point, the plan may not be as successful as it would be otherwise. If a utility's rates do not reflect current costs, the intended efficiency incentives provided by the PBR mechanism will be blunted either because lower than appropriate rates do not provide the company with a realistic opportunity to earn a reasonable return for its shareholders, despite efforts to control costs, or because higher than appropriate rates enable the company to provide more than adequate returns to shareholders without continually implementing new efficiency improvements. Especially under a PBR plan that has a longer term, it is essential that the starting point reasonably reflect a utility's current cost of providing service.

By initiating the PBR Plans subsequent to the completion of FG&E's upcoming rate proceedings, rather than basing it on past, and most likely, outdated cost relationships (some of which have been in place for up to 18 years), reflected in FG&E's current base rates, the use of fair and compensatory cast-off rates will be assured as the starting point for the Plans and for subsequent rate adjustments under the Plans.

IV. THE UNDERPINNINGS OF FG&E'S PBR PLANS

Q. Please provide a general explanation of the underlying concepts supporting FG&E's PBR Plans.

A. Recognizing that traditional monopoly regulation is no longer adequately responsive to real-time choices facing utility customers, regulators and utilities have encouraged incremental change and experimentation with regulatory alternatives for a number of years. The Department itself has recognized that traditional regulation has numerous inherent flaws and that a PBR approach provides "a potentially superior alternative to traditional regulation" and "a means of better facilitating the transition to a more competitive environment in the electric and gas industries, with benefits for both consumers and the industries."[8]

In recent years, PBR has been the underlying concept in support of the movement of the telecommunications and energy industries from cost of service regulation (i.e., rate of return regulation) towards a broader concept of price control and incentives. While PBR has a wide range of meanings in the energy industry, including alternative regulation, performance-based regulation, incentive regulation, price caps, value-based pricing, and market-based pricing. In all cases, the meaning always denotes a departure from traditional cost-based

[8] D.P.U. 94-158 at 10.

regulation or ratemaking where assessment of the utility's overall costs of providing service is required periodically to adjust its rates.

In an industry often guided by precedent, this experimentation with varying substitutes for market competition has now been extended into the PBR environment. A review of the numerous alternative regulatory mechanisms and programs in effect throughout North America, together with the range of PBR programs approved in Massachusetts, demonstrates that unique company situations and regulatory concerns have required numerous and separate regulatory approaches. This wide array of choices and structures offers companies and regulators flexibility in addressing specific needs and objectives, especially in the rapidly changing competitive markets of today's energy utility.

In general terms, PBR describes ratemaking arrangements that provide a utility with a stronger incentive to control costs and resulting charges to customers than under traditional cost-based regulation. The specific ratemaking tools that embody PBR concepts can either be targeted to certain categories of costs, or certain utility functional areas, or they can be comprehensive in nature, covering most or all of a utility's business activities. Mechanisms labeled as PBR can include fuel or gas cost incentive mechanisms, earnings sharing mechanisms, price or revenue caps, rate freeze provisions, margin sharing mechanisms, and reliability and other performance standards.

Q. What do you mean by the phrase "traditional cost of service regulation?"

A. Under traditional cost of service regulation, base rates charged to customers are set to cover the utility's total revenue requirement. The utility's total revenue requirement is the sum of its operating expenses and return on its invested capital, or the authorized rate of return multiplied by the company's invested capital. Once rates are set to recover the utility's revenue requirement, they remain in effect until the utility files a request to increase rates or the regulatory body initiates a proceeding to reduce the utility's rates based on earnings claimed to be above the level previously authorized by the regulator. This form of regulation has frequently been termed cost-plus regulation.

Q. How do PBR mechanisms differ from traditional cost of service regulation?

A. PBR mechanisms replace the cost-plus mechanics under traditional cost of service regulation with incentive or performance based ratemaking tools designed to encourage efficient utility operations. PBR mechanisms fundamentally change the rate setting process from a focus on cost recovery to one focused on financial and operational incentives. A utility is no longer provided with a direct link between its approved level of costs and the necessary level of revenues generated through rates so that it is given a reasonable opportunity to earn its allowed return on invested capital. Rather, with PBR mechanisms, the utility has strong incentives to control costs because it can retain financial benefits associated with improving the efficiency of its operations, and because it has a reduced ability to pass on cost increases typically allowed under cost of service regulation. At the same time, under PBR, it is expected that marketplace benefits will be provided to consumers by promoting more efficient utility operations, cost control, and opportunities for reduced gas and electric rates.[9]

Q. Please describe the expected benefits of PBR programs.

A. As energy markets have become increasingly competitive, the drawbacks associated with cost of service regulation become prominent. For example, making enhancements to a utility's infrastructure without support from current rates, or continuing past operation and maintenance programs without continuing reassessment, may be reasonable courses of action under a traditional ratemaking regime, but they often cause utility rates to increase. The expectation of higher rates, all other things being equal, can make the utility less competitive in the marketplace. In addition, cost of service regulation involves lengthy regulatory proceedings and tends to be relatively inflexible to changes in the marketplace.

PBR programs are relatively more responsive and flexible. Appropriately designed, they also better emulate competitive market conditions by rewarding efficient operations and sound investment decisions. In a competitive market, a firm is described as a "price taker," with its profitability dependent upon its ability to control its costs of delivering the product to customers. Prices are set in the marketplace and do not necessarily vary with the individual

[9] D.P.U. 94-158 at 40-41.

firm's costs. Rather, factors such as general inflationary pressures that affect the costs of all firms in the market have greater influence on the market price. As in a true competitive market, a PBR program decouples the utility's costs from the prices it charges for service. Because the utility's costs no longer drive prices as they do under cost of service regulation, the utility becomes a "price taker" and its profitability depends on its ability to control costs, much like a competitive firm.

Q. Doesn't cost of service regulation provide similar incentives for efficient operations?

A. Some observers maintain that cost of service regulation provides similar rewards because of the regulatory lag in setting rates through the process of filing and litigating general rate cases. However, the prospects of obtaining short-lived rewards provides little or no real incentive to utility management as a result of the longer-term consequences of reducing expenses and controlling investment costs in the cost-plus rate setting environment.

Q. With its potential rewards focused on efficient utility operations and cost controls, could PBR mechanisms also have the unintended effect of leading to a deterioration in the service quality and reliability of the utility's gas or electric distribution system?

A. While this concern has been expressed within the overall discussion of PBR concepts, it is also recognized that a utility's continuing profitability, and its very existence in the long term, depends on its provision of high quality and reliable service. Where feasible, customers will discontinue their use of inferior service over time if the utility's service becomes unacceptable to them. While fully-competitive electricity options appear more limited, continued developments in, for example, micro-turbine and fuel cell technologies will enable customers to discontinue service from their current electric distribution company, therefore, adding to the competitive supply source options that customers have today in many areas. Short-term cost cutting that results in reduced reliability or deterioration in service quality is simply not a prudent long-term course of action for a utility's management.

At the same time, it is clear that regulators will not ignore any material deterioration in a utility's service quality, should it occur, regardless of its cause. One regulatory response to ensure that service remains a utility priority is to establish service quality benchmarks with well-defined rewards for exceeding the standards, or penalties for falling short of the standards. In fact, FG&E has stated in joint comments submitted to the Department,[10] within the context of PBR plans, that it believes that the promulgation of service quality guidelines by the Department will allow utility companies to serve their customers in a consistent and effective manner while allowing the companies to maintain their overall levels of service as restructured gas and electric markets develop in the future.

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[10] Joint Comments of the Investor-owned Natural Gas Local Distribution Companies and Five Investor-owned Electric Distribution Companies, *submitted in* D.T.E. 99-84 at 2 (Dec. 3, 1999).

Q. Has the Department recognized the limitations of traditional cost of service regulation and the expected benefits of PBR?

A. Yes. In its February 24, 1995 Order in D.P.U. 94-158, "Incentive Regulation for Electric and Gas Companies," the Department cited, at page 9, the following defects associated with traditional cost of service regulation:

- Lack of incentive for cost control, through its inherent bias favoring expenditures that can be passed on to customers
- Inflexible and less than efficient pricing
- Persistent cross-subsidies among service classifications
- Poor asset performance
- Risk-adverse management
- Disincentives for innovation
- Costly method of regulation characterized by long lags both in reflecting and controlling actual utility operations and their costs.

The Department also noted at page 10 that, "[t]hese limitations have particularly acute consequences for gas and electric utilities in the rapidly changing regulatory and market environment" and concludes that incentive regulation provides "a potentially superior alternative to traditional regulation" and "a means of better facilitating the transition to a more competitive environment in the electric and gas industries, with benefits for both consumers and the industries."

Q. What are the key considerations in designing a PBR mechanism for a utility's PBR plan?

A. Among the key design considerations, a PBR mechanism should be balanced. It should have the potential to provide benefits to all utility stakeholders (i.e., the company, its customers, and the regulator). The PBR mechanism should clearly articulate the standard by which performance is to be measured, and it should be administratively easy to track that desired performance. The PBR mechanism should result in a reduced regulatory burden. The mechanism should be effective for a long enough time period to allow the utility to adapt its business strategies and operational initiatives to the changed regulatory framework. Finally, the PBR mechanism should be designed so as not to conflict with sound policy objectives, such as the provision of safe, reliable, and quality service.

Q. Has the Department suggested evaluative criteria to be used in the design of PBR mechanisms?

A. Yes, it has. In addition to specific criteria articulated in its past Orders addressing various utility PBR proposals, in Docket No. D.P.U. 94-158,[11] the Department indicated that PBR mechanisms should:

- Be consistent with Department regulations, statutes, and governing precedents

[11] D.P.U. 94-158 at 66.

- Be consistent with market-based regulation and enhanced competition
- Safeguard system integrity, reliability, and current policy objectives
- Reward utility performance and address exogenous costs
- Focus on comprehensive results
- Incorporate well-defined, measurable indicators
- Be consistent with accounting standards and acceptable within the financial community
- Have a minimum time horizon to give the incentive plan enough time to achieve its goals
- Provide for re-evaluation of the program at least once during its term to monitor goal attainment and make required modifications, as necessary
- Be administratively simple

Q. Do FG&E's PBR Plans reflect the key design considerations that you just identified and do they fully satisfy the Department's stated criteria for PBR mechanisms?

A. Yes, they do. FG&E's PBR Plans are based on a price cap structure, consistent with the Department's evolving precedents for PBR filings. In general terms, the Plans are comprehensive and contain well-defined, measurable indicators that are not subject to manipulation. The Plans are administratively simple to implement, an especially important consideration for a small company such as FG&E. The Plans provide assurances that FG&E's customers will benefit from their implementation, and they address the future incurrence of any significant costs that are beyond FG&E's control. Each Plan incorporates a mid-course assessment to ensure that it is meeting the desired goals. Finally, the Plans ensure that FG&E will continue to focus on the provision of service quality through incorporation of revenue penalties when its performance does not meet specified standards.

V. COMPONENTS OF FG&E'S PBR PLANS

Q. Please describe the structural components of FG&E's PBR Plans.

A. Formal documents that constitute FG&E's Gas and Electric PBR Plans have been submitted as part of its PBR filings. These Plans will become effective on January 1, 2003, based on new base rates to be approved as a result of FG&E's May 17, 2002 rate case filings. FG&E's base rates in these filings are expected to become effective no later than December 1, 2002. Each of the PBR Plans has a10-year term.

FG&E's base rates are proposed to be adjusted annually using two separate price cap calculations for gas operations and a single price cap calculation for electric operations. All other non–base rate components contained in FG&E's Tariff for Gas Service and Tariff for Electric Service are unaffected by the PBR Plan and will continue to operate as they currently do.

Q. If the Company's distribution base rates are adjusted by the overall percentage change using the price cap formula, will the Company's revenue requirements be accurately adjusted?

A. For the most part yes, the large majority of the adjustment can be attributed to distribution base rates. However, some of the Company's non-gas costs for its Gas Division are recovered through its Cost of Gas Adjustment ("CGA") mechanism. Specifically, as a result of the gas service unbundling process in Massachusetts, the Company was directed to exclude indirect gas costs, comprised of five categories of supply-related expense from its distribution base rates. These include: (1) production-related non-gas costs associated with its manufactured gas plants, (2) gas supply administrative expenses such as gas acquisition and dispatching costs and FERC proceedings costs concerning gas supply matters, (3) supply-related bad debt expense, (4) commodity-related working capital costs and (5) production related overhead associated with these items. These costs are included in its CGA mechanism, to be recovered only from its gas sales service customers. The supply-related bad debt expense and commodity-related working capital costs are reconciled to actual as part of the CGA mechanism and therefore would not need to be adjusted under a price cap. However, the other three items are not reconciled to actual costs. In order to properly adjust CGA revenues so that these expense components are treated similarly to the Company's other non-gas costs recovered through distribution base rates, the Company proposes to apply the net of the inflation index and enhanced productivity offset to these costs as if they were included in, and recovered through, its current distribution base rates.

Q. Please continue with your explanation of the various price cap calculations used to adjust FG&E's base rates.

A. The first set of price changes in each Plan, computed according to the following formulas, would become effective July 1, 2004:

1) For the gas and electric distribution base rates, the price cap calculation for a given year, year t, is performed as follows:

$$P_t = P_{t-1} \text{ x } (1 + I_t - X_t + Z_t - S_t)$$

where:

P_t	=	FG&E's weighted average price in year t
P_{t-1}	=	FG&E's weighted average price in the prior year, year (t-1)
I_t	=	Inflation index for year t based on the inflation rate between calendar years (t-2) and (t-1)
X_t	=	Enhanced productivity offset for year t
Z_t	=	Exogenous cost factor in year t
S_t	=	Service quality revenue penalty factor in year t

The percentage price change, used to compute distribution base price cap rate adjustments for each of FG&E's customer classes, equals $(P_t/P_{t-1}) - 1$.

2) For each of the three components of the gas production base rates (i.e., LPLNG, DAFP, and PRO), the calculation for a given year, year t, is performed as follows:

$$P^*_t = P^*_{t-1} \text{ x } (1 + I_t - X_t)$$

where:

P^*_t = FG&E's production base rate component in year t

P^*_{t-1} = FG&E's production base rate component in the prior year, (t-1)

I_t = Inflation index for year t, based on the inflation rate between calendar years (t-2) and (t-1)

X_t = Enhanced productivity offset for year t

The production base rate percentage price change, used to compute price cap rate adjustments for each gas production base rate component, equals the net of the inflation index (I_t) and the enhanced productivity offset (X_t), or ($I_t - X_t$).

Q. How does FG&E propose to apply these resulting price changes to its customers?

A. Each of the above-described distribution base rate price changes would be spread uniformly to all customer classes, although each Plan provides for some limited flexibility. Inherent in this treatment is the assumption that FG&E's PBR cast-off rates will be cost-based to the fullest extent possible recognizing the judgmental considerations, endorsed by the Department, of applying non-cost factors to the rate design process. During the terms of the

PBR Plans, FG&E may propose non-uniform application of the price cap adjustments consistent with Department precedent.

The production base rate percentage price change calculated under the price cap will be applied to each of the production base rate components (i.e. LPLNG, DAFP, and PRO rate factors).

Q. Are there any other structural components of FG&E's PBR Plans that you wish to highlight?

A. Yes. As part of the price cap rate changes, each PBR Plan provides for adjustments if FG&E's service quality performance does not meet the standards as set forth in each of its filed SQPs. Customers are, thus, provided assurances that these PBR Plans will not encourage FG&E to lessen its efforts to provide quality services to its customers.

Finally, the Plans envision a mid-course assessment by the Department after the 5th year of operation of the Plans. FG&E will also provide the Department with a recommendation and supporting rationale pertaining to the disposition of the Plans at the end of their ten-year terms.

Q. Why was a 10-year term chosen for FG&E's PBR Plans?

A. A PBR mechanism should be in effect for a long enough period of time to allow the utility company to implement medium- and long-term strategic plans consistent with the incentives provided by the PBR mechanism and to allow regulators to assess the effectiveness of the Plan.. The term should also be long enough to achieve the regulatory and administrative cost savings expected under a PBR plan. FG&E's proposed 10-year term, together with a mid-term assessment of the Plans after the 5th year, fully satisfy these objectives.

Q. Regarding the price cap formula, please explain the weighted average price calculation?

A. For the Gas Division's price cap calculation, the weighted average price is based on FG&E's current base rates. The weighted average price (P_{t-1}) in the prior year (t-1), is calculated by dividing weather-normalized gas distribution base revenue in year (t-1), by weather-normalized gas sales units, (stated in therms), in year (t-1). Weather normalization will be performed based on the same procedures endorsed by the Department in establishing FG&E's revenue requirements in its 2002 general rate cases. For the Electric Division's price cap calculation, the weighted average price will be determined the same way with the exception that no weather normalization calculation will be performed in accordance with Department decisions.

Q. What inflation index is FG&E proposing to use and how will it be calculated?

A. Inflation is measured according to the Gross Domestic Product chain-weighted Price Index ("GDP-PI"), a widely-accepted, comprehensive measure of the aggregate of prices of all goods and services comprising the United States' national income. For purposes of the price cap calculation, the GDP-PI in a given year will be the average of the GDP-PIs at the end of each calendar quarter of the year. The inflation index to be used in the price formula is simply the percentage change in the average GDP-PI in the most recent calendar year compared to the last calendar year's average.

Finally, in both of the above price cap calculations, if the inflation index (I_t) is less than the enhanced productivity offset (X_t), then the resulting term ($I_t - X_t$) will be set to zero for purposes of the price cap calculations. Using a negative value for the ($I_t - X_t$) term would unfairly penalize FG&E, during a period of obvious economic disruption and would be contrary to the stated intent of the price cap adjustment within the context of the Company's PBR Plans.

Q. Please explain the enhanced productivity offset used in the Company's price cap mechanism?

A. The enhanced productivity offset used in FG&E's price cap mechanism recognizes and captures the Department's precedents and policies regarding the utilization of a productivity offset factor to create incentives for distribution utilities to control costs below the prevailing level of inflation. In a prior Boston Gas Company rate case, the Department ultimately found that "this offset includes two productivity components: (1) an historic productivity component, the productivity growth index; and (2) a future productivity component, the consumer dividend factor."[12] This same structural approach was applied by the Department

[12] D.P.U. 96-50-C (Phase I) at 56.

to Berkshire Gas Company.[13] In view of these regulatory and structural preferences of the Department, FG&E proposes the use of a two-part enhanced productivity offset in its gas and electric PBR Plans.

Specifically, FG&E proposes that the enhanced productivity offset in both of its PBR Plans be set at 0.5 percent, with the base productivity component set at zero and the consumer dividend component set at 0.5 percent.

Q. How was the level of the base productivity offset determined by FG&E?

A. The econometric principles and theoretical underpinnings of total factor productivity, as applied to monopoly utility operations, have been widely discussed and debated in multiple proceedings before the Department (as well as in other regulatory jurisdictions in North America and abroad). FG&E agrees with the Department that, "the productivity and input price growth indices are intended to reflect the average annual growth in productivity and input prices, during a specified time period, for the companies that comprise a regulated industry. Considered jointly, these indices should reflect the average annual increase in per

[13] D.T.E. 01-56, at 21.

unit costs, during the specified period, for the regulated companies."[14] In this case and in the Berkshire Gas decision, the Department concluded that a base productivity offset of zero was reasonable.[15] In my opinion, the primary support for this level of productivity offset emanated from the productivity factor study undertaken by Boston Gas Company.[16] Based on these clear Department precedents, FG&E has chosen to adopt a base productivity offset of zero in its PBR Plans.

Q. Why does FG&E believe these previous Department decisions and the supporting productivity factor study results also should apply to its PBR Plans?

A. FG&E's conclusion is supported by several important factors. First, the decision to use a base productivity offset of zero is consistent with the Department's finding in multiple Orders that "because productivity offsets are not company-specific, it is appropriate to use a productivity offset developed for another LDC."[17]

Second, in a similar manner to the conclusion reached by Berkshire Gas Company, the high costs to conduct a productivity factor study, as compared with the likely results of such a

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[14] D.P.U. 96-50 (Phase I) at 273.

[15] Berkshire Gas Co., D.T.E. 01-56 at 21-22; Eastern Enterprises/Colonial Gas, D.T.E. 98-128 at 63.

[16] Boston Gas Co., D.P.U. 96-50 at 261-278.

[17] Eastern Enterprises/Colonial Gas, D.T.E. 98-128, at 63-65; Berkshire Gas Co., D.T.E. 01-56 at 21-22.

study, would far outweigh any incremental accuracy or display any significant changes. The costs for a new total factor productivity study could range as high as $400,000 to $500,000. Even a smaller scale effort to update critical information, such as extending the data series or collecting and analyzing new cost share weights for the input price index, and then analyzing this data under any changed conditions for FG&E, would cost several hundred thousand dollars. Even if comparable data were available in a timely fashion, which is a problem given the increasing confidentiality of the competitive energy industry, and absent any specific information to the contrary, any changes in the industry productivity levels since the Boston Gas study would likely be mirrored in the U. S. economy as a whole, and therefore would not materially change the base productivity offset. In addition, the cost of these studies would more likely be greater than any incremental change to the base productivity offset, and therefore would not be a beneficial investment by FG&E on behalf of its customers. This cost/benefit determination is consistent with Department policy requiring that utilities strike some balance between accuracy and cost with respect to decisions to undertake quantitative studies.[18]

Third, FG&E provides gas and electric services similar to other utilities, and is affected by many of the same external pressures on labor, material, and equipment costs. In Eastern Enterprise/Colonial Gas, the Department found that “[t]he productivity offset approved for

[18] Boston Gas Co., D.P.U. 94-14.

Boston Gas is not necessarily unique to Boston Gas or any specific gas company since the productivity and input-price-growth indices were derived from a sample of many LDCs."[19]

Q. Why does FG&E believe that the base productivity offset should be the same for both of its PBR Plans?

A. There are several factors that support this conclusion. First, since the start of energy utility deregulation activities in the 1980s, electric and gas distribution companies alike have experienced many of the same input price pressures and have selected similar technology investments, system improvements, and process changes resulting in productivity benefits for their customers. This is especially true for combination companies, such as FG&E, and for companies in regions that have seen an increase in price competition, customer choice, and energy deregulation, such as the Northeast. In fact, in some jurisdictions, such as California, the productivity offsets used for the gas and electric divisions of combination distribution utilities are not dissimilar. Therefore, a total factor productivity study of northeastern electric distribution firms would produce similar results to the productivity study conducted by Boston Gas Company.

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19 Eastern Enterprises/Colonial Gas, D.T.E. 98-128.

Second, since FG&E's has centralized and shares many of the same services between its electric and gas operations, both parts of FG&E's utility business are subject to many of the same pressures on the essential input components of labor, materials, equipment and capital. For example, FG&E's electric and gas operations share a single union labor contract, a common call center, joint operation centers, centralized billing and accounting functions, and centralized engineering and design departments, as discussed below.

Finally, even if a new total factor productivity study did derive material differences in the level of productivity between electric and gas utilities, the required costs to quantify these differences would not likely offset any incremental benefits, as I explained earlier in my testimony.

Q. Are there other reasons for the Company recommending a base productivity offset of zero?

A. Yes. If you consider that a base productivity offset, in general terms, represents the estimated reductions in the costs of a utility company realized through productivity gains, as measured by the comparable gains that other utility companies have achieved historically, then a base productivity offset of zero reflects FG&E's success over time in meeting or exceeding the productivity levels demonstrated by the industry, in general, and by the energy utility sector, specifically.

FG&E has managed to control its operating costs over an extended period of time by centralizing a number of activities and improving the efficiencies of these activities. FG&E's customers have benefited from the integrated and shared services concept applied to the Unitil family of companies, which eliminates duplicate functions, captures certain economies of scale, reduces capital spending requirements, and improves the quality of service through the adoption of "best practices" techniques. Currently, service functions performed at Unitil Service Corp. and provided to all distribution companies fall into six areas: customer services; engineering and operations; regulatory, finance and accounting; energy services; technology; and corporate and administration.

FG&E and its customers have also seen the benefits of a new centralized 24-hour customer service center, a fully centralized engineering department, and an Operations Systems function that centralizes safety and environmental services, undertakes new technology development and oversees the standardization of operating practices. New standardized policies, procedures and work practices have been developed for vegetation management, transmission inspections, substation maintenance, and other environmental matters.

These centralized services have contributed to savings for FG&E and its sister companies. According to one benchmark, over the period from 1984 to 2001, total Unitil system revenues have increased 95% while total employees decreased by 3%, in the same period.

In addition, by cost effectively investing in key new technologies and systems in order to implement the restructuring and unbundling of its gas and electric operations (e.g., customer information and billing systems, competitive supplier interface systems), FG&E has been able to avoid a majority of the impact of inflation and subsequent price increases over an extended period of time.

Based on these results, price caps each with a base productivity offset of zero fairly represent the historical success of FG&E's Gas and Electric Divisions.

Q. How was the level of the consumer dividend determined by FG&E?

A. The Department stated its rationale for including a consumer dividend factor in the productivity offset contained in the price cap formula in its NYNEX Order: "Because well-designed price cap regulation is superior to rate of return regulation in promoting economic efficiency, the average annual productivity of the industry should be higher if the firms in the industry are regulated under a price cap rather than ROR. Therefore, if the productivity factor is based on the historic experience of the industry, the productivity offset for the future should be higher to compensate for this expected productivity gain."[20]

In its Boston Gas Company Order, the Department stated, "The consumer dividend factor serves as a 'future' productivity factor because it is intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to performance-based

[20] D.P.U. 94-50 at 165-166.

regulation."[21]

For these same reasons, FG&E proposes the inclusion of a consumer dividend in its enhanced productivity offset. Furthermore, FG&E believes the level of the consumer dividend contained in its PBR Plans is consistent with the Department's ultimate determination of the consumer dividend for Boston Gas Company. Initially, the Department had established a consumer dividend of one percent, balancing several factors. In its original Order, the Department recognized "the potential for efficiency improvements is greater in the telecommunications industry than in the gas distribution industry due to rapid technological advances occurring in the telecommunications industry."[22] Therefore, when viewing the consumer dividend of one percent established for NYNEX within the context of the energy utility business, the Department ultimately concluded that for Boston Gas Company, a consumer dividend established at a reduced level of 0.5 percent was appropriate.[23]

Q. Based on your understanding of its historical operational performance and its expectations for the future, do you believe an enhanced productivity offset of 0.5 percent is appropriate for FG&E?

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21 D.P.U. 96-50 (Phase I) at 278-279.

22 D.P.U. 96-50 (Phase I) at 279.

23 D.P.U. 96-50-C (Phase I) at 58.

A. Yes, I do. Internal productivity increases and efforts, including those noted previously, have allowed FG&E to keep pace with its competition and with the level of productivity experienced by other firms already operating under some forms of PBR. For instance, FG&E has some of the lowest gas distribution rates in the state and its electric distribution rates are at the average level for the state. Moreover, by the time any proposed changes in rates are received, the Gas Division will not have increased rates for four years and major components of the Electric Division rate structure will have been in place for 18 years. In my opinion, this demonstrates that FG&E's customers have been receiving the benefits of its internal productivity activities and initiatives.

Similarly, since FG&E has restructured its gas and electric divisions in response to unbundling and other industry and regulatory initiatives, it has not yet realized any significant benefits due to these ongoing changes. In fact, in these early stages of restructuring, FG&E is now incurring increased costs for providing various services and support to third party energy suppliers, acting as a conduit between these competitors, and responding to numerous data requests, meetings, information tracking requirements, and other newly designated responsibilities. These costs have been incurred by FG&E, without yet having received the expected benefits associated with these energy industry changes.

Even an enhanced productivity offset of 0.5 percent can be viewed as being aggressive for FG&E, given its relative size, organizational structure, and existing productivity and technology investments. FG&E must continue to be innovative and successful in developing more efficient service processes, systems, and personnel just to keep up with inflation, and there are relatively fewer options remaining in these areas for a pure distribution utility such as FG&E. For instance, based on combined base revenues of $25 million for FG&E's Gas and Electric Divisions, it would have to generate over $125,000 per year of additional cost savings to just keep pace with an enhanced productivity offset of 0.5 percent. This is more than $1 million in the aggregate over the term of its PBR Plans.

Based on these perspectives, I believe that an enhanced productivity offset of 0.5 percent is entirely consistent with Department precedent and makes sound economic sense within the broader context of FG&E's PBR Plans.

Q. Please explain the exogenous cost factor included in FG&E's PBR Plans.

A. The exogenous cost factor, used only in the price cap calculation applicable to distribution base rate, consists of cost changes, both positive and negative, that are beyond FG&E's control and not reflected in the inflation index, including but not limited to changes in tax laws; accounting changes; regulatory, judicial and legislative changes affecting the energy utility industry; and *force majeure*. In addition, the exogenous cost factor for FG&E's Electric Division may also include Company-specific cost changes related to any environmental remediation, including abatement and removal of asbestos containing materials associated with FG&E's former electric generating station located at Sawyer

Passway. The exogenous cost factor enables FG&E to recover changes in exogenous costs by incorporating these recoverable cost changes into the weighted average price calculation each year. The threshold for inclusion of an exogenous cost item in the price calculation is $25,000 under the Gas Plan[24] and $75,000 under the Electric Plan.[25] FG&E selected these threshold levels based on its understanding of the Department's PBR precedents pertaining to exogenous cost recovery for gas utilities.[26] In calculating the exogenous cost factor for the current year, any incremental, or new exogenous costs would be submitted for recovery and any non-recurring exogenous costs from the prior year would first be removed from the calculation. This different treatment for non-recurring costs is entirely appropriate considering the unique nature of these costs such as governmental agency assessments (e.g., DOT), one-time tax rebates or property assessments, extraordinary storm damages, and the like.

Q. Are these types of costs necessarily unique to the local gas or electric distribution industries?

A. No, not at all. In the examples cited above, such types of costs can be incurred not only by gas and electric utilities alike, but by other industries as well. In fact, their lack of uniqueness to gas or electric distribution utilities should not have any bearing whatsoever

[24] $20,087,677 x 0.13% (rounded).

[25] $57,024,273 x 0.13% (rounded).

[26] See Berkshire Gas Co., D.T.E. 01-56 at 22, and Eastern Enterprise/Colonial Gas, D.T.E. 98-128 at 57.

on the characterization of these costs as exogenous for any particular utility, and their subsequent recovery. Rather, the underlying nature of these costs should be the determining factor in defining them as exogenous costs, including their uncontrollability and relative significance as measured by the established cost thresholds.

Q. Couldn't the inflation index contained in its PBR Plans serve to compensate FG&E for any exogenous costs it incurs over time?

A. No. The purpose of the inflation index is to annually adjust the utility's base rates to reflect changes in the <u>level</u> of costs incurred in providing service to its customers. It is not supposed to adjust rates over time to reflect changes in the <u>types</u> of costs the utility incurs. This is entirely consistent with the manner in which the utility's cast-off rates are established. These rates are meant to reflect the known and measurable operating costs of the utility, as measured at a particular point in time, whether or not such costs are of a recurring or non-recurring nature. Once the PBR Plan becomes effective, the inflation index applies to these rates to adjust the levels of the underlying costs consistent with the broader cost trends in the economy. The nature of these costs are known with certainty, but the future levels of these costs is not, so the inflation index serves to accommodate the expectation that the levels of these costs will change over time. To the extent a utility incurs exogenous costs, since such costs are not considered to be embedded in the utility's base rates, they cannot be accounted for through the application of the inflation index to the utility's then current base rates.

Q. Please explain why FG&E has defined costs related to *force majeure* conditions and costs related to environmental remediation at Sawyer Passway as exogenous costs?

A. FG&E has treated costs related to *force majeure* conditions as exogenous because by definition these costs are unpredictable, and therefore uncontrollable acts of nature. Hurricanes, ice storms, floods, wind and other forces of nature can cause severe and unpredicted damage to utility infrastructures and equipment. FG&E desires to recover through base rates any abnormal and unbudgeted costs incurred as a result of responding to these incidents, repairing systems, and generally restoring the utility systems to their previous conditions through the exogenous cost factor mechanism included in its Plans.

FG&E treats any future costs of environmental remediation at Swayer Passway as exogenous costs, because FG&E may incur some unknown level of costs in this area as a result of ongoing environmental proceedings. If this occurs, these FG&E-specific costs would not be accounted for through the application of the inflation index to the utility's then-current base rates, nor would they be embedded in the original cast-off rates. These costs should more appropriately be directly recovered through the exogenous cost adjustment.

Q. How will FG&E treat any penalties resulting from service quality performance?

A. Consistent with the Department's Order in Docket No. DTE 99-84, and as described in FG&E's SQPs, FG&E will calculate revenue penalties, if any, associated with service quality performance measures on a calendar year basis. Each year during the term of the

Plans, FG&E will make a compliance filing by March 1st that summarizes the calculation of any revenue penalties associated with FG&E's performance under its SQPs for the prior calendar year. The first Annual Service Quality Reports under FG&E's PBR Plans for which penalties would apply covers performance for calendar year 2003, consistent with FG&E's Price Cap Compliance Filing, as will be reflected in its March 1, 2004 filing. In the event that FG&E's service quality performance results in revenue penalties for any calendar year, FG&E will reflect this amount in its price cap calculation for distribution base rates.

Q. Please explain the relationship between the price cap and service quality components of FG&E's PBR Plans.

A. Each Plan's implementation, including the price cap component, is predicated upon FG&E's approved SQP that includes the use of a 2 percent maximum transmission and distribution revenue penalty, specified calculation procedures, and defined performance measures. The calculation procedures are described in FG&E's filed SQPs and in the Department's Service Quality Guidelines. The defined performance measures pertain to Class I and Class II odor call response time, SAIDI, SAIFI, lost-time work accident rate, telephone answering rate, service appointments met, on-cycle meter readings, consumer division cases, and billing adjustments. FG&E's PBR Plans are predicated on the expectation of subsequent Department approval of FG&E-specific benchmarks for each of these measures, generally consistent with FG&E's SQPs. In the event that the Department alters the structure, measurement, calculation procedures, or benchmark calculation approaches prior to January

1, 2003, or at any time during the effective term of the PBR Plan, FG&E reserves the right to terminate each PBR Plan or to propose modifications in each PBR Plan, subject to Department approval.

Q. Do the Plans allow FG&E any pricing flexibility apart from the flexibility you described earlier?

A. Yes. Separate and apart from the price cap calculation, the Plans allow FG&E to negotiate a special contract with any general class customer in accordance with Department policies. That is, the contract price for a special contract customer must exceed FG&E's marginal cost to provide service to the customer. The contractual price and service conditions will become effective upon FG&E filing the contract with the Department and will remain effective until the expiration date of the contract or the end of the Plans, whichever occurs first. Revenues under these contracts will not be subject to a price cap adjustment, and the revenue associated with the contracts would not be subject to, or included in, a price calculation.

Q. When will FG&E make filings to implement price cap changes under its PBR Plans, and what types of information will be included in each filing?

A. By May 1st each year, beginning in 2004, FG&E will make price cap compliance filings to implement its periodic rate changes. The Electric and Gas PBR Plan documents submitted as part of this filing provide the format of computational schedules that will accompany each price cap filing.

Q. Do FG&E's PBR Plans provide for a mid-course assessment during the terms of the Plans?

A. Yes. The Plans provide for a mid-course assessment of the Plan and an end of term recommendation for the Plan. Accompanying its May 1, 2008 Price Cap Compliance Filing, FG&E will file information with the Department on the performance of the Plan. The Department will then evaluate the Plan in its entirety to determine whether the Plan will be continued for the remainder of its term. In its May 1, 2008 Price Cap Compliance Filing, FG&E may propose either that the Plan be retained as currently structured for the remainder of the 10-year term, or that specific modifications in the Plan be made for the remainder of the term, or that the Plan be terminated prior to the end of the 10-year term.

In its May 1, 2012 Price Cap Compliance Filing, FG&E will provide the Department with a recommendation and supporting rationale pertaining to the disposition of the Plan at the end of its ten-year term. The recommendation may call for retention of the Plan as currently structured, propose specific modifications in the Plan, or require termination of the Plan.

Q. Mr. Feingold, does that complete your direct testimony?

A. Yes, it does.

RUSSELL A. FEINGOLD

EDUCATION

- Bachelor of Science degree in Electrical Engineering from Washington University, St. Louis.
- Master of Science degree in Financial Management from Polytechnic Institute of New York

PROFESSIONAL EMPLOYMENT

1997 – Present **Navigant Consulting, Inc.**
Managing Director, Regulation & Litigation Support Practice

1990 – 1997 **R.J. Rudden Associates, Inc**.
Vice President and Director

1985 – 1990 **Price Waterhouse**
Director, Gas Regulatory Services
Public Utilities Industry Services Group

1978 – 1985 **Stone & Webster Management Consultants, Inc.**
Executive Consultant
Regulatory Services Division

1973 – 1978 **Port Authority of New York and New Jersey**
Staff Engineer and Utility Rate Specialist
Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Montana Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New York Public Service Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

EDUCATIONAL AND TRAINING ACTIVITIES

- Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, 1985 – 2002
- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress)

PUBLICATIONS AND PRESENTATIONS

- "LDC Perspectives on Managing Price Volatility" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.
- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.
- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999

- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.
- "Asset and Resource Migration Strategies," presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.
- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- "State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.
- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.
- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.
- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.
- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.
- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.
- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.
- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.
- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.
- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.
- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.
- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.
- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.
- Seminar organizer and moderator at the American Gas Association seminar, "Integrated Resource Planning: A Primer," December 1991.

- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.
- "Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.
- "Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.
- "Design of Distribution Company Gas Rates," presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.
- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, "Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," 1988-1990.
- "Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.
- "So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.
- "Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.
- "Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.
- "Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.
- "Gas Transportation Rates - An Integral Part of a Competitive Marketplace," *American Gas Association, Financial Quarterly Review*, Summer 1987.
- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review*, October 1983.
- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.

- Cofounder, course director and instructor in the annual course, “Principles of Gas Utility Rate Regulation” sponsored by The Center for Professional Advancement 1982-1987.
- “Current Rate and Regulatory Issues,” presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Rate and Strategic Issues Committee of the American Gas Association
- Member, Energy Bar Association
- Member, Institute of Electrical and Electronic Engineers
- Listed in Who’s Who of Emerging Leaders in America, 1989-1992

(Current as of March 2002)